BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application	)	
of Entergy Arkansas, Inc., Mid South	)	
TransCo LLC, Transmission Company	)	
Arkansas, LLC and ITC Midsouth LLC	)	File No. EO-2013-0396
for Approval of Transfer of Assets and	)	
Certificate of Convenience and Necessity,	)	
and Merger and, in connection therewith,	)	
Certain Other Related Transactions	)	

EXHIBIT TWV-2

Transmission Planning Criteria

ITC MIDWEST

TRANSMISSION PLANNING CRITERIA

100 kV AND ABOVE[1]

May, 2012

[1] This manual defines and explains the current planning criteria **and will be reviewed and updated as required**. The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the transmission system unless some deviation is justified as a result of special, economic or unusual considerations. Such instances should not necessarily be considered to conflict with this criterion or to justify revising the criteria, but should be recognized as unusual and special cases. The reliability implications of all such deviations shall be quantified to the extent possible or otherwise qualified sufficiently to ensure minimal reliability impacts. The planning criteria in this manual are guidelines to assist the planning engineer in making capital project and/or operating solution proposals for anticipated system needs.

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1 Goal

This document describes the criteria to be used in assessing the reliability of the ITC Midwest transmission (100 kV and above[2]) system. This transmission planning criteria is intended to result in an ITC Midwest transmission system that economically and reliably allows our transmission system customers to serve load from generation of choice.

2 NERC & MRO Reliability Criteria

ITC Midwest adheres to the NERC Reliability Standards and the MRO Standards.

In Table 1 of the NERC TPL Standards (TPL-001-0, TPL-002-0, TPL-003-0 & TPL-004-0), four categories of conditions have been defined as follows (SLG is single line ground and 3ϕ is three phase):

[2] For these criteria, this includes transformers with a low side voltage rating above 100 kV.

Table 1 – Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Elements(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	*All Facilities in Service*	Yes	No	No
B Event resulting in the loss of a single element.	Single Line to Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator	Yes	No[b]	No
	2. Transmission Circuit	Yes	No[b]	No
	3. Transformer	Yes	No[b]	No
	Loss of an Element without Fault	Yes	No[b]	No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section	Yes	Planned/Controlled[c]	No
	2. Breaker (failure or internal fault)	Yes	Planned/Controlled[c]	No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3 or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3 or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing. 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]:	Yes	Planned/ Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[f]	Yes	Planned/ Controlled[c]	No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator	Yes	Planned/ Controlled[c]	No
	7. Transformer	Yes	Planned/ Controlled[c]	No
	8. Transmission Circuit	Yes	Planned/ Controlled[c]	No
	9. Bus Section	Yes	Planned/ Controlled[c]	No

D[d] Extreme event resulting in two or more (multiple) elements removed or cascading out of service.	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section	Evaluate for risks and consequences - May involve substantial loss of customer demand and generation in a widespread area or areas. - Portions of all of the interconnected systems may or may not achieve a new, stable operating point. - Evaluation of these events may require joint studies with neighboring systems.
	3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal fault)	
	6. Loss of towerline with three or more circuits	
	7. All transmission lines on a common right of way	
	8. Loss of a substation (one voltage level plus transformers)	
	9. Loss of a switching station (one voltage level plus transformers)	
	10. Loss of all generating units at a station	
	11. Loss of a large load or major load center	
	12. Failure of a fully redundant Special Protection Scheme (or Remedial Action Scheme) to operate when required.	
	13. Operation, partial operation, or misoperation of a fully redundant Special Protection Scheme (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate.	
	14. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization.	

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

The following requirements are specified in the MRO Standard TPL-503-MRO-01 System Performance.

Table 2 – MRO System Performance Table[1]

NERC Categories	Transient Voltage Deviation Limits	Rotor Angle Oscillation Damping Ratio Limits
A	Nothing in addition to NERC Requirements	
B (See Notes 2 and 6)	Minimum 0.70 p.u. at any bus. (See Note 5)	Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips. (See Note 7)
C (See Notes 2, 3, and 6)	Minimum 0.70 p.u. at any bus. (See Note 5)	Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips. (See Note 7)
D (See Notes 2, 3, and 4)	Nothing in addition to NERC Requirements	

Notes:

1. The MRO System Performance Table including the notes applies to the initial transient period following the contingency (up to 20 seconds) and the post-disturbance period (20 seconds to the end of the allowed readjustment period as described in MRO Regional Reliability Standard TPL-503-MRO-01_R1.4).

2. The following summarizes the automatic and manual readjustments that are permissible for all NERC Category B disturbances.

   A. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units.

   B. Capacitor and reactor switching - The number of capacitors and reactors which may be switched is limited to those which could be switched during the allowed readjustment period. This includes those capacitors and reactors that would be switched by automatic controls within the same period.

   C. Adjustment of Load Tap Changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the allowed readjustment period.

   D. Adjustment of phase shifters to the extent possible within the allowed readjustment period.

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   D. Adjustment of phase shifters to the extent possible within the allowed readjustment period.

E. An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period.

F. Generation rejection to the extent possible within the allowed readjustment period. Shall not exceed the normal operating reserve of the generation reserve sharing pool to which the MRO Member belongs or of the MRO Member itself if the MRO Member self-provides generation reserves.

G. Transmission reconfiguration - Automatic and operator initiated tripping of transmission lines or transformers to the extent possible within the allowed readjustment period.

H. Automatic or manual tripping of interruptible load or curtailment of or pre-determined redispatching of Firm Point-to-Point Transmission Service to the extent possible within the allowed readjustment period. Curtailment of Firm Transmission Service within the readjustment period is permitted only to prepare for the next contingency.

3. The following additional readjustment may be considered for all NERC Category C contingencies.

A. Automatic or manual tripping of firm Network or Native Load or curtailment of or predetermined redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.

4. The following additional readjustments may be considered for all NERC Category D contingencies.

A. Planned and/or controlled islanding - Automatic underfrequency load shedding, as specified in NERC PRC-006-0, is permitted to arrest declining frequency and generation rejection is permitted to arrest increasing frequency in order to assure continued operation within the resulting islands.

B. Automatic undervoltage load shedding is permissible to arrest declining voltages and prevent widespread voltage collapse.

5. The voltage of 0.7 per unit is the point at which load dropping begins to occur due to motor contactors dropping out and induction motors stalling and also the point where sensitive (power electronics) begin to drop out.

6. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC Category B disturbances, unless documentation is provided showing the actual relays will not trip for the event. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC Category C disturbances, unless documentation is provided that demonstrates that a relay trip will not result in instability (including voltage instability), uncontrolled separation, or cascading outages.

7. Damping is required during the initial transient period following the disturbance (up to 20 seconds). The machine rotor angle damping ratio is determined by appropriate modal analysis (for example, Prony analysis). Alternatively, the Rotor Angle Oscillation Damping Factor or Successive Positive Peak Ratio (SPPR) can be calculated directly from the rotor angle, where the rotor angle response allows such direct calculation. For a disturbance with a fault, the SPPR must be less than 0.95 or the damping factor must be greater than 5%. For a disturbance without a fault, the SPPR must be less than 0.90 or the damping factor must be greater than 10%. (The SPPR criteria were chosen to define positive rotor angle damping for study purposes in MAPP. The Rotor Angle Oscillation Damping Ratio Limits were derived from the SPPR criteria.)

3 Introduction to ITC Midwest Planning Criteria

This planning criteria manual sets down the planning guidelines used to determine system needs and justify modifications to the transmission system. This manual defines and explains the current planning criteria and will be reviewed and updated as required.

The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the transmission system unless some deviation is justified as a result of special, economical or unusual considerations. Such instances should not necessarily be considered to conflict with this criterion or to justify revising the criteria, but should be recognized as unusual and special cases. The reliability implications of all such deviations shall be quantified to the extent possible or otherwise qualified sufficiently to ensure minimal reliability impacts. The planning criteria in this manual are guidelines to assist the planning engineer in making capital project and/or operating solution proposals for anticipated system needs.

Planning for the transmission system is intended to provide a network capable of transmitting power between generating sources and loads. The ITC Midwest system is utilized by various generation sources and load throughout the Eastern Interconnection via Network Integration Transmission Service or various other forms of Transmission Service. The implementation of the projects and operating solutions identified by application of this planning criteria shall result in a ITC Midwest system for which the probability of initiating cascading failures is very low. The system should also provide operating flexibility including, but not limited to, allowing maintenance outages. Non-consequential loss of load may be tolerated for extreme contingencies.

In meeting the above objectives, the planning engineer must recognize the present state-of-the-art with regard to equipment, construction practices, scheduling and the practical needs of operating the electrical system. It must be recognized that thermal overloading can shorten the equipment life and lead to sudden failures and that abnormal voltages can also cause equipment failures and/or voltage sensitive equipment to be affected. The planning engineer also needs to be cognizant of intangible considerations, such as the social and political implications of his work as well as visual and ecological effects. In particular, one social implication that the planning engineer needs to consider is the social benefit of the loads being able to access the most economical generation available. Many of these elements cannot be guided by exact rules and the engineer's judgment must be factored into the proposed projects. In summary, the material gathered in this manual is intended to provide basic system planning guidelines. The planning engineer, however, must still apply ingenuity, experience and judgment in order to develop projects which lead to an economic and reliable power system and supports the access to economical generation. Where judgment is used, it should be recognized as such and documented so as to be part of the record for future planning.

4 Thermal Loading and Voltage Planning Criteria

4.1 Description

The transmission system is used to transmit power and energy from interconnected generation plants to interconnected loads. Some of the generation and load that utilize the ITC Midwest system are not directly interconnected with the ITC Midwest system but are part of the larger interconnected grid and utilize the ITC Midwest system through its ties with neighboring systems.

4.2 Design Considerations

The ITC Midwest system should be designed such that foreseeable normal and contingency conditions do not result in equipment damage or in exceeding acceptable loss of load (see Table 3 – ITC Midwest Planning Criteria for allowable load loss by contingency type). Planning studies are to be carried out for projected annual peak system load conditions, but the planning criteria also holds for load levels less than annual peak. Additionally, the planning criteria evaluates projected shutdown conditions (a single element shutdown plus a single element forced out) at a lower load level.

The ITC Midwest system will be planned to be within its thermal capacity, to remain stable, to be within equipment short circuit capabilities, and to be within acceptable voltage limits while meeting projected needs of users of the transmission system. These needs may be communicated by reservations on the transmission system including network service or through other mechanisms.

Studies to determine transmission needs for a given power plant will be based on the maximum reasonable expected generation output from that plant and adverse, but credible, dispatch scenarios for other nearby generation.

MRO models are typically used to evaluate system performance for compliance with the NERC TPL Standards. Details of model development can be found in the MRO Model Building Manual.

For those conditions and events that do not meet the performance requirements of Table 3 – ITC Midwest Planning Criteria, corrective plans involving capital projects will be developed. Operating guides will only be used as interim solutions, prior to completion of system upgrades.

4.3 Project Proposal Guidelines

Project proposals will be submitted if one or more of the following guidelines are met.

- Replacement of equipment which is unsafe to operate and/or presents a hazard. This includes projects required to replace interrupting devices that could be subjected to fault currents which exceed momentary or interrupting ratings, as well as projects required to replace equipment that periodic maintenance tests have shown to have incipient failure.

- Replacement of equipment that presents a costly maintenance burden. This includes projects required to replace equipment that periodic maintenance tests have shown increasing economic costs to maintain for reasons such as that equipment that is, or is becoming, obsolete.

- Interconnection of reasonably documented new customers or committed increases in load at existing customer stations. Related projects should be proposed if one or more of the planning criteria are violated.

- Relocation of ITC Midwest facilities on public property as required by federal, state, county or local governmental units. Other requests for relocations are to be done only if the requestor has contracted to pay for the relocation or if economic justification exists.

- Repair, rebuild or replacement of equipment which has failed.

- Repair, rebuild or replacement of facilities needed to provide acceptable reliability. This includes facilities which due to design no longer provides acceptable reliability and/or facilities in which normal maintenance is not effective to maintain reliability due to the overall condition of the facilities.

- Requirements to maintain spare equipment to a level sufficient to provide timely replacements for normal failure rates.

- Mitigation of instances with violations or projected violations of the planning criteria.

- Purchase of corridor, station and/or substation sites as needed for other projects. Approved property purchases can also be associated with reasonable expected future needs.

Reasonable future conditions such as load growth, changes in regional and interregional system flow patterns and future generators must be considered when developing projects. The goal is to develop a robust transmission system today which can be efficiently expanded to reliably and economically accommodate tomorrow's load and generation patterns.

4.4 Voltage and Facility Loading Criteria

4.4.1 Generally Applicable Criteria

Table 3 – ITC Midwest Planning Criteria

Description	NERC Category	Allowable Load Loss	Ratings Used [c]	Load Level [h]	Minimum Voltage [b, e, f]	Maximum Voltage [b, e, f]
System Normal	A	none	normal	100%	95%	105% [k]
Single Generator	B1	none	emergency	100%	93% [j]	110% [j, l]
Single UG Cable	B2	none [a]	emergency	100%	93% [j]	110% [j, l]
Single OH Line	B2	none [a]	emergency	100%	93% [j]	110% [j, l]
Single Transformer	B3	none [a]	emergency	100%	93% [j]	110% [j, l]
Bus Section	C1	none [a,g]	emergency	100%	93% [j]	110% [j, l]
Circuit Breaker	C2	none [a,g]	emergency	100%	93% [j]	110% [j, l]
Shutdown + Contingency	B1, B2 or B3	none [a,g]	emergency	70%	93%	110% [j, l]
Double Circuit Tower [i]	C5	none [a,g]	emergency	100%	93% [j]	110% [j, l]
Double Contingencies [d]						
1. After First Contingency (Prior to System Re-Adjustment)	C3	none [a]	emergency	100%	93%	110% [l]
2. After First Contingency (After System Re-Adjustment)	C3	none [a]	normal	100%	95%	105% [k]
3. After Second Contingency (Prior to System Re-Adjustment)	C3	none [a,g]	emergency	100%	90%	110% [l]
4. After Second Contingency (After System Re-Adjustment)	C3	none [a,g]	emergency	100%	93%	105% [k]
Extreme Contingencies [d]	D	no cascading	emergency	100%	no cascading	no cascading

a) There may be some consequential load loss in the event of the loss of a radial circuit, a transformer in direct series with a radial circuit or the loss of a load fed from a radial tap off of a network circuit provided the load lost was served directly by the outaged facility.

b) System Normal voltage limits represent pre-contingent system voltage limits (SOLs) under normal system conditions. Post-contingent system voltage limits (SOLs) are emergency voltage limits under abnormal or emergency system conditions.

c) The normal and emergency ratings are developed in accordance with PWR-601 ITC Midwest Equipment Thermal Load Ratings. The normal and emergency rating may be the same.

d) The NERC Planning Standards consider a single category B event followed by operator intervention followed by another category B event as a category C event. Action must be taken within 30 minutes of initial disturbance. The loss of two elements without time between for operator action is interpreted by ITC Midwest to be more severe than category C and is treated like an extreme contingency.

e) All Nuclear Plant Interface Requirements (NPIRs) in the ITCMW footprint shall be monitored and upheld. The normal and contingent DAEC 161 kV voltage requirement is a minimum of 99.2% and a maximum of 104.14%.

f) The voltage limits listed are steady state voltage limits. Voltage control devices (e.g., tap changers, switched shunts, and phase shifting transformers) should be set to control during the analysis.

g) There may be some load loss to a defined pocket of load as a direct consequence of the system topology.

h) The Load Level shown is the maximum load level (in percent of the system peak) to which this part of the criteria should be applied. It is also valid at any load level less than that shown.

i) Any two circuits of a multiple circuit towerline excludes transmission circuits where multiple circuit towers are used over a cumulative distance of 1 mile or less in length.

j) Voltage must be restorable to the System Normal range after system adjustments. Action must be taken within 30 minutes of disturbance.

k) 107% for 115 kV buses.

l) System studies should monitor at the System Normal Maximum Voltage.

Tests should be applied as appropriate to examine the system's susceptibility to voltage collapse. The system should be monitored for voltage deviations greater than 5%. The reactive reserve in an area (comprised of "unused" reactive capability of generators or shunt capacitors) may be monitored in studies to identify possible voltage collapse scenarios. Low reactive reserves may be an indication of being near the "knee" of the PV curve.

When contingencies result in buses being isolated from all sources of the same or higher voltage, it is not considered a violation of the planning criteria for voltages on the isolated buses to be outside the parameters of Table 3 - ITC Midwest Planning Criteria, provided that the voltages on the underlying system are within acceptable limits.

Projects should be proposed if the loading on system elements (overhead conductors, underground cables and/or station equipment), minimum voltages, maximum voltages, or the amount of load loss are outside of the applicable contingency category parameters as set forth in of Table 3 - ITC Midwest Planning Criteria for any reasonably expected generation dispatch pattern, or a dispatch that represent an average condition. Where projects are proposed for additional dispatch scenarios, their use will be justified and documented.

4.4.2 Shutdown Conditions

For load levels at or below the maximum planned for load level with shutdowns (see Table 3 - ITC Midwest Planning Criteria) it is expected that the shutdown of a single component would result in element loadings and system voltage within normal ranges. Further, it is expected that contingent loss of a component on top of the shutdown of a single component would result in element loadings and system voltages within emergency ranges.

There must be a significant, continuous time during the year when a system element can be shutdown for inspection, maintenance, adjacent hazard and/or element replacement. Planning studies must therefore evaluate the system under shutdown conditions using the maximum planned load level with shutdowns (see Table 3 - ITC Midwest Planning Criteria). The maximum planned for load level with shutdowns should periodically be re-evaluated to ensure that the application of that criterion is consistent with the requirement of having a significant, continuous time during the year when a system element can be shutdown for inspection, maintenance, adjacent hazard and/or element replacement.

MRO summer off-peak models are typically used to evaluate system performance for shutdown conditions. MRO defines summer off-peak (shoulder) load as 70% of summer peak load conditions.

4.4.3 Single Contingency Followed by Operator Action Followed by Another Single Contingency

The forced outage of a single generator, transmission circuit (or portion thereof) or transformer followed by operator interaction and then followed by another forced outage of a single generator, transmission circuit (or portion thereof) or transformer is considered to be a NERC Category C event. For these events, NERC Reliability Standard TPL-003-0 requires all remaining system elements to be within applicable thermal and voltage limits and also allows load shedding. ITC Midwest has separated the allowable load shedding in the Standard into two categories. In the first category, load is shed via operator-initiated actions following the loss of two elements in order to keep the loading of system elements within established longer-term emergency ratings and system voltages within established limits. Following the loss of two elements and prior to load shed, the loading of system elements must be within established short-term emergency ratings. Since ITC Midwest does not use short-term emergency ratings, this type of load shedding is not allowed. In the second category, supply to a defined pocket of load is lost as the direct consequence of the system topology. An example of the second category would be a substation which serves distribution load and has only two supplies. The concurrent outage of both supplies will result in the load at that substation being dropped. This type of load shedding is allowed.

4.4.5 NERC Category D – Extreme Event

The ITC Midwest system will be evaluated using a number of extreme contingencies that are judged by Planning to be critical. It is not expected that it will be possible to evaluate all possible facility outages that fall into NERC Category D. These events may involve substantial load and generation loss in a widespread area. These critical category D contingencies should not result in cascading outages beyond the ITC Midwest system area and any immediately adjacent areas.

5 Stability Criteria

Stability is the ability of a generator or power system to reach an acceptable steady-state operating point following a disturbance. This requires that thermal loadings, load loss, and voltage following the disturbance are within the guidelines established in Table 3 – ITC Midwest Planning Criteria.

Generator and system stability shall be maintained during and after the most severe of the contingencies listed below:

1. With the transmission system normal, a three-phase fault at the most critical location[a] with normal[b] clearing.
2. Simultaneous phase-to-ground faults on two transmission circuits on a multiple circuit tower with normal[b] clearing.
3. A single phase-to-ground fault at the most critical location[a] with delayed[c] clearing.

4. With one element (transmission line, transformer, protective relay, or circuit breaker) initially out of service, a three phase-to-ground fault at the most critical location[a] with normal[b] clearing.
5. A single phase-to-ground internal breaker fault with normal[b] clearing.
6. Where single pole tripping is enabled, single phase-to-ground faults on the transmission circuit with successful reclosing, and unsuccessful reclosing due to permanent single phase-to-ground faults with normal[b] clearing.

a) Faults should be placed on generators, transmission circuits, transformers, and bus sections.
b) Normal clearing means that all protective equipment worked as intended and within design guidelines.
c) Delayed clearing means that a circuit breaker, relay or communication channel has malfunctioned or failed to operate within design guidelines. If the delayed clearing is due to a failure to operate, local and remote backup clearance is appraised.

Performance during and after the disturbance shall meet the requirements of the NERC TPL standard's Table 1 – Transmission System Standards – Normal and Emergency Conditions, and the MRO System Performance Table of MRO Standard TPL-503-MRO-01.

A one-cycle[3] safety margin must be added to the actual or planned fault clearing time.

6 Short Circuit Criteria

Short circuit currents are evaluated in accordance with industry standards as specified in American National Standards report ANSI C37.5-1981 for older breakers rated on the total current (asymmetrical) basis and American Standards Association report C37.010-1979 (Reaff 1988) for new breakers rated on a symmetrical current basis.

In general, fault currents must be within specified momentary and/or interrupting ratings for studies made with all facilities in service, and with generators and synchronous motors represented by their appropriate (usually sub-transient saturated) reactance.

7 Power Quality/Reliability Criteria for Delivery Points

Details of Power Quality and Reliability Criteria for Delivery Points are covered in the individual Interconnection Agreement Documents with the Load Serving Entities. The Planning Engineer shall propose projects as required in those agreements.

[3] The basis for the one-cycle safety margin is that it has historically been used by MAPP and is listed in the MAPP Members Reliability Criteria and Study Procedures Manual dated April 2009, and the MISO Transmission Planning Business Practices Manual dated 11-20-10.

8 Voltage Deviation Standards

8.1 Capacitor Switching

The maximum percent change (step-change) in system voltage under normal system conditions shall be 3% when sizing capacitor banks.

8.2 Loss of Generation

Over the normal generation availability range, with all transmission elements in service, the voltage change measured anywhere in the system shall be considered for a single generator tripping.

8.3 Loss of an Element

Over the normal generation availability range, the voltage change measured anywhere in the system shall be considered for a single transmission element tripping.

9 Coordination with Other Transmission Systems

9.1 Joint Planning

The ITC Midwest system has interconnections with neighboring systems. These systems include neighboring transmission systems as well as distribution systems. The contractual commitments with the interconnected neighbors, as well as the properties of interconnected operations require coordinated joint planning with others of not only the interconnection facilities, but also consideration of the networks contiguous to those interconnections. Joint planning is accomplished by participation in several regional planning groups.

9.2 Interchange Capability

Interconnections with other transmission systems are intended to facilitate the economic and reliability needs of generators and loads directly interconnected with the ITC Midwest system. In addition, these interconnections can also support the economic and reliability needs of generators and loads not directly interconnected with the ITC Midwest system. Interchange capability is the amount of power that can be transferred across transmission systems without exceeding transmission system facility limitations. Accordingly, the evaluation and planning of interchange capability is necessarily a joint effort by the concerned utilities. ITC Midwest participates in the transfer analysis performed by several regional planning groups.

10 Special Protection Systems (SPS)

It is ITC Midwest policy that new Special Protection Schemes (SPS) not be installed on the ITC Midwest system. ITC Midwest will not support the installation of an SPS on a neighboring system whose purpose is to mitigate potential issues on the ITC Midwest system.

For those SPS's that have already been placed in service, periodic reviews should be performed to ensure that the scheme is deactivated when the conditions requiring its use no longer exist or system improvements to remove the SPS are warranted.

ITC MIDWEST

SUBTRANSMISSION PLANNING CRITERIA

BELOW 100 kV[1]

May, 2012

[1] This manual defines and explains the current planning criteria **and will be reviewed and updated as required**. The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the subtransmission system unless some deviation is justified as a result of special, economic or unusual considerations. Such instances should not necessarily be considered to conflict with this criterion or to justify revising the criteria, but should be recognized as unusual and special cases. The reliability implications of all such deviations shall be quantified to the extent possible or otherwise qualified sufficiently to ensure minimal reliability impacts. The planning criteria in this manual are guidelines to assist the planning engineer in making capital project and/or operating solution proposals for anticipated system needs.

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1 Goal

This document describes the criteria to be used in assessing the reliability of the ITC Midwest subtransmission (below 100 kV[2]) system. This subtransmission planning criteria is intended to result in an ITC Midwest subtransmission system that economically and reliably allows our subtransmission system customers to serve load from generation of choice.

2 Thermal Loading and Voltage Planning Criteria

2.1 Design Considerations

The ITC Midwest system should be designed such that foreseeable normal and contingency conditions do not result in equipment damage or in exceeding acceptable loss of load (see Table 1 – ITC Midwest Subtransmission Planning Criteria for allowable load loss by contingency type). Planning studies are to be carried out for projected annual peak system load conditions, but the planning criteria also holds for load levels less than annual peak.

The ITC Midwest system will be planned to be within its thermal capacity, to remain stable, to be within equipment short circuit capabilities, and to be within acceptable voltage limits while meeting projected needs of users of the subtransmission system. These needs may be communicated by reservations on the subtransmission system including network service or through other mechanisms.

Studies to determine subtransmission needs for a given power plant will be based on the maximum reasonable expected generation output from that plant and adverse, but credible, dispatch scenarios for other nearby generation.

MRO models are typically used to evaluate system performance. Details of model development can be found in the MRO Model Building Manual.

For those conditions and events that do not meet the performance requirements of Table 1 – ITC Midwest Subtransmission Planning Criteria, corrective plans involving capital projects will be developed. Operating guides will only be used as interim solutions, prior to completion of system upgrades.

2.2 Project Proposal Guidelines

Project proposals will be submitted if one or more of the following guidelines are met.

- Replacement of equipment which is unsafe to operate and/or presents a hazard. This includes projects required to replace interrupting devices that could be subjected to fault

[2] For these criteria, this includes transformers with a low side voltage rating below 100 kV.

currents which exceed momentary or interrupting ratings, as well as projects required to replace equipment that periodic maintenance tests have shown to have incipient failure.

- Replacement of equipment that presents a costly maintenance burden. This includes projects required to replace equipment that periodic maintenance tests have shown increasing economic costs to maintain for reasons such as that equipment that is, or is becoming, obsolete.

- Interconnection of reasonably documented new customers or committed increases in load at existing customer stations. Related projects should be proposed if one or more of the planning criteria are violated.

- Relocation of ITC Midwest facilities on public property as required by federal, state, county or local governmental units. Other requests for relocations are to be done only if the requestor has contracted to pay for the relocation or if economic justification exists.

- Repair, rebuild or replacement of equipment which has failed.

- Repair, rebuild or replacement of facilities needed to provide acceptable reliability. This includes facilities which due to design no longer provides acceptable reliability and/or facilities in which normal maintenance is not effective to maintain reliability due to the overall condition of the facilities.

- Requirements to maintain spare equipment to a level sufficient to provide timely replacements for normal failure rates.

- Mitigation of instances with violations or projected violations of the planning criteria.

- Purchase of corridor, station and/or substation sites as needed for other projects. Approved property purchases can also be associated with reasonable expected future needs.

Reasonable future conditions such as load growth, changes in regional and interregional system flow patterns and future generators must be considered when developing projects. The goal is to develop a robust subtransmission system today which can be efficiently expanded to reliably and economically accommodate tomorrow's load and generation patterns.

2.3 Voltage and Facility Loading Criteria

Table 1 – ITC Midwest Subtransmission Planning Criteria

Description	NERC Category	Allowable Load Loss	Ratings Used [b]	Load Level [e]	Minimum Voltage [c, d, j]	Maximum Voltage [d, j]
System Normal [f]	A	none	normal	100%	95% [m]	105% [m]
Single Generator [g]	B1	none	emergency	100%	93% [n, k]	110% [k, p]
Single UG Cable [g]	B2	none [a]	emergency	100%	93% [n, k]	110% [k, p]
Single OH Line [g]	B2	none [a]	emergency	100%	93% [n, k]	110% [k, p]
Single Transformer [g]	B3	none [a]	emergency	100%	93% [n, k]	110% [k, p]
Bus Section [g]	C1	none [a, h]	emergency	100%	93% [n, k]	110% [k, p]
Double Circuit Tower [g, i]	C5	none [a, h]	emergency	100%	93% [n, k]	110% [k, p]
Circuit Breaker > 100 kV	C2	none [a, h]	emergency	100%	90% [o]	110% [k, p]
Double Contingencies > 100 kV [l]	C3	none [a, h]	emergency	100%	90% [o]	110% [k, p]

a) There may be some consequential load loss in the event of the loss of a radial circuit, a transformer in direct series with a radial circuit or the loss of a load fed from a radial tap off of a network circuit provided the load lost was served directly by the outaged facility.

b) The normal and emergency ratings are developed in accordance with PWR-601 ITC Midwest Equipment Thermal Load Ratings. The normal and emergency rating may be the same.

c) The Minimum Voltage requirement for 69 kV retail users without voltage regulation is 97.5 % normal, and 95.0% post-contingency. This includes Cargill (Eddyville), Griffin Wheel, Keokuk Steel, and Ogilvie Mills.

d) The voltage limits listed are steady state voltage limits. Voltage control devices (e.g., tap changers, switched shunts, and phase shifting transformers) should be set to control during the analysis.

e) The Load Level shown is the maximum load level (in percent of the system peak) to which this part of the criteria should be applied. It is also valid at any load level less than that shown.

f) Normal conditions include an appropriate set of scenarios that consider appropriate generators not in the dispatch. This would typically include municipal generators or a single generator dispatched off in the area of study.

g) Emergency conditions include an appropriate set of scenarios that consider appropriate generators not in the dispatch in addition to the transmission element outages. This would typically include at least a single generator dispatched off prior to applying the contingency under study.

h) There may be some load loss to a defined pocket of load as a direct consequence of the system topology.

i) Any two circuits of a multiple circuit towerline excludes transmission circuits where multiple circuit towers are used over a cumulative distance of 1 mile or less in length.

j) System Normal voltage limits represent pre-contingent system voltage limits (SOLs) under normal system conditions. Post-contingent system voltage limits (SOLs) are emergency voltage limits under abnormal or emergency system conditions.

k) Voltage must be restorable to the System Normal range after system adjustments. Action must be taken within 30 minutes of disturbance.

l) The NERC Planning Standards consider a single category B event followed by operator intervention followed by another category B event as a category C event. Action must be taken within 30 minutes of initial disturbance. The loss of two elements without time between for operator action is interpreted by ITC Midwest to be more severe than category C and is treated like an extreme contingency.

m) System Normal Minimum and Maximum Voltage limits for 34.5 kV are 102% and 108% respectively.

n) 99% for 34.5 kV buses

o) 96% for 34.5 kV buses. Voltage must be restorable to 93% for 69 kV and 99% for 34 kV after system adjustments. Action must be taken within 30 minutes of disturbance.

p) System studies should monitor at the System Normal Maximum Voltage.

Tests should be applied as appropriate to examine the system's susceptibility to voltage collapse. The system should be monitored for voltage deviations greater than 5%. The reactive reserve in an area (comprised of "unused" reactive capability of generators or shunt capacitors) may be monitored in studies to identify possible voltage collapse scenarios. Low reactive reserves may be an indication of being near the "knee" of the PV curve.

When contingencies result in buses being isolated from all sources of the same or higher voltage, it is not considered a violation of the planning criteria for voltages on the isolated buses to be outside the parameters of Table 1 - ITC Midwest Subtransmission Planning Criteria, provided that the voltages on the underlying system are within acceptable limits.

Projects should be proposed if the loading on system elements (overhead conductors, underground cables and/or station equipment), minimum voltages, maximum voltages, or the amount of load loss are outside of the applicable contingency category parameters as set forth in of Table 1 - ITC Midwest Subtransmission Planning Criteria for any reasonably expected generation dispatch pattern, or a dispatch that represent an average condition. Where projects are proposed for additional dispatch scenarios, their use will be justified and documented.

3 Stability Criteria

Stability is the ability of a generator or power system to reach an acceptable steady-state operating point following a disturbance. This requires that thermal loadings, load loss, and voltage following the disturbance are within the guidelines established in Table 1 – ITC Midwest Subtransmission Planning Criteria.

Generator and system stability shall be maintained during and after the most severe of the contingencies listed below:

1. With the transmission system normal, a three-phase fault at the most critical location[a] with normal[b] clearing.
2. Simultaneous phase-to-ground faults on two transmission circuits on a multiple circuit tower with normal[b] clearing.
3. A single phase-to-ground fault at the most critical location[a] with delayed[c] clearing.
4. With one element (transmission line, transformer, protective relay, or circuit breaker) initially out of service, a three phase-to-ground fault at the most critical location[a] with normal[b] clearing.
5. A single phase-to-ground internal breaker fault with normal[b] clearing.

a) Faults should be placed on generators, transmission circuits, transformers, and bus sections.
b) Normal clearing means that all protective equipment worked as intended and within design guidelines.
c) Delayed clearing means that a circuit breaker, relay or communication channel has malfunctioned or failed to operate within design guidelines. If the delayed clearing is due to a failure to operate, local and remote backup clearance is appraised.

Performance during and after the disturbance shall meet the requirements of the NERC TPL standard's Table 1 – Transmission System Standards – Normal and Emergency Conditions, and the requirements of the MRO System Performance Table of MRO Standard TPL-503-MRO-01.

A one-cycle[3] safety margin must be added to the actual or planned fault clearing time.

4 Short Circuit Criteria

Short circuit currents are evaluated in accordance with industry standards as specified in American National Standards report ANSI C37.5-1981 for older breakers rated on the total current (asymmetrical) basis and American Standards Association report C37.010-1979 (Reaff 1988) for new breakers rated on a symmetrical current basis.

In general, fault currents must be within specified momentary and/or interrupting ratings for studies made with all facilities in service, and with generators and synchronous motors represented by their appropriate (usually sub-transient saturated) reactance.

5 Power Quality/Reliability Criteria for Delivery Points

Details of Power Quality and Reliability Criteria for Delivery Points are covered in the individual Interconnection Agreement Documents with the Load Serving Entities. The Planning Engineer shall propose projects as required in those agreements.

6 Voltage Deviation Standards

6.1 Capacitor Switching

The maximum percent change (step-change) in system voltage under normal system conditions shall be 3% when sizing capacitor banks.

6.2 Loss of Generation

Over the normal generation availability range, with all transmission elements in service, the voltage change measured anywhere in the system shall be considered for a single generator tripping.

[3] The basis for the one-cycle safety margin is that it has historically been used by MAPP and is listed in the MAPP Members Reliability Criteria and Study Procedures Manual dated April 2009, and the MISO Transmission Planning Business Practices Manual dated 11-20-10.

6.3 Loss of an Element

Over the normal generation availability range, the voltage change measured anywhere in the system shall be considered for a single transmission element tripping.

7 Coordination with Other Transmission Systems

The ITC Midwest system has interconnections with neighboring systems. These systems include neighboring transmission systems as well as distribution systems. The contractual commitments with the interconnected neighbors, as well as the properties of interconnected operations require coordinated joint planning with others of not only the interconnection facilities, but also consideration of the networks contiguous to those interconnections. Joint planning is accomplished by participation in several regional planning groups.

8 Special Protection Systems (SPS)

It is ITC Midwest policy that new Special Protection Schemes (SPS) not be installed on the ITC Midwest system. ITC Midwest will not support the installation of an SPS on a neighboring system whose purpose is to mitigate potential issues on the ITC Midwest system.

For those SPS's that have already been placed in service, periodic reviews should be performed to ensure that the scheme is deactivated when the conditions requiring its use no longer exist or system improvements to remove the SPS are warranted.

United States of America
Federal Energy Regulatory Commission

2010 FERC Form 715
Annual Transmission Planning and Evaluation Report

Part 4: Transmission Planning Reliability Criteria

ITC Great Plains subscribes to all current NERC and Southwest Power Pool ("SPP") Reliability Standards. The present SPP reliability criteria are available on the web at: http://www.spp.org/publications/Criteria02042010-with%20AppendicesCurrent.pdf

ITC Great Plains is a member of the Southwest Power Pool. The criteria used by the SPP to determine available transmission capacity can be found in Citeria 4 of the SPP Criteria, available on the web at the link listed above.

ITC *TRANSMISSION*
MICHIGAN ELECTRIC TRANSMISSION COMPANY

TRANSMISSION PLANNING CRITERIA

February, 2012

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1 Goal

This is the joint planning criteria for the ITC*Transmission* and Michigan Electric Transmission Company transmission systems. For simplicity in the remainder of this report, the joint systems will be referred to as the "Transmission System". This transmission planning criteria is intended to result in a Transmission System that economically and reliably allows our transmission system customers to serve their load from any generation of their choice.

2 NERC & ReliabilityFirst Reliability Criteria

ITC*Transmission* and Michigan Electric Transmission Company adhere to all current NERC and Reliability*First* Reliability Standards.

ITC*Transmission* and Michigan Electric Transmission Company also adhere to the legacy ECAR Document 1 approved October 20, 1967, revised November 6, 1980 and revised again July 27, 1998. ECAR Document 1 is entitled "Reliability Criteria for Evaluation and Simulated Testing of ECAR Bulk power supply system".

As members of Reliability*First*, ITC*Transmission* and Michigan Electric Transmission Company adhere to the legacy ECAR Document No. 1 and the statement contained therein that, "...The ECAR members recognize the impossibility of anticipating, and testing for, all possible contingencies that could occur on either the present or the future Bulk Electric Systems within ECAR. They believe, therefore, that the transmission reliability criteria should serve primarily as a means to measure the strength of the systems to withstand the entire spectrum of contingencies, that may or may not be readily visualized, rather than comprise a detailed listing of probable disturbances. Ultimately, the strength of the system as planned and operated must be sufficient to assure that any load loss has not been the result of or does not result in uncontrolled power interruptions. In view of this, the selection of reliability criteria is based not on whether specific contingencies for which the system is being tested are themselves highly probable but rather on whether they constitute an effective and practical means to stress the system and thus test its ability to avoid uncontrolled power interruptions."

In Table 1 of the NERC Planning Standards, four categories of conditions have been defined as follows (SLG is single line to ground and 3ϕ is three phase):

Table 1 – NERC Planning Standards

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Elements(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line to Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator	Yes	No	No
	2. Transmission Circuit	Yes	No	No
	3. Transformer	Yes	No	No
	Loss of an Element without Fault	Yes	No	No
	Single Pole Block, Normal Clearing: 4. Single Pole (dc) Line	Yes	No	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing: 1. Bus Section	Yes	Planned/Controlled	No
	2. Breaker (failure or internal fault)	Yes	Planned/Controlled	No
	SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing: 3. Category B (B1, B2, B3 or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3 or B4) contingency	Yes	Planned/Controlled	No
	Bipolar Block, with Normal Clearing: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing:	Yes	Planned/Controlled	No
	5. Any two circuits of a multiple circuit tower line.	Yes	Planned/Controlled	No
	SLG Fault, with Delayed Clearing (stuck breaker or protection system failure): 6. Generator	Yes	Planned/Controlled	No
	7. Transformer	Yes	Planned/Controlled	No
	8. Transmission Circuit	Yes	Planned/Controlled	No
	9. Bus Section	Yes	Planned/Controlled	No

D Extreme event resulting in two or more (multiple) elements removed or cascading out of service.	3Ø Fault, with Delayed Clearing (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section	Evaluate for risks and consequences - May involve substantial loss of customer demand and generation in a widespread area or areas. - Portions of all of the interconnected systems may or may not achieve a new, stable operating point. - Evaluation of these events may require joint studies with neighboring systems.
	3Ø Fault, with Normal Clearing: 5. Breaker (failure or internal fault)	
	6. Loss of tower line with three or more circuits	
	7. All transmission lines on a common right of way	
	8. Loss of a substation (one voltage level plus transformers)	
	9. Loss of a switching station (one voltage level plus transformers)	
	10. Loss of all generating units at a station	
	11. Loss of a large load or major load center	
	12. Failure of a fully redundant Special Protection Scheme (or Remedial Action Scheme) to operate when required.	
	13. Operation, partial operation, or miss-operation of a fully redundant Special Protection Scheme (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate.	
	14. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization.	

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

3 Introduction to Transmission System Planning Criteria

This planning criteria manual identifies the planning guidelines used to determine system needs and justify modifications to the transmission system. This manual defines and explains the current planning criteria and will be reviewed and updated as required.

The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the transmission system unless some deviation is justified as a result of special, economical or unusual considerations. Such instances should not necessarily be considered to conflict with this criterion or to justify revising the criteria, but should be recognized as unusual and special cases. The reliability implications of all such deviations shall be quantified to the extent possible or otherwise qualified sufficiently to ensure minimal reliability impacts. The planning criteria in this manual are guidelines to assist the planning engineer in making capital project and/or operating solution proposals for anticipated system needs.

Planning for the transmission system is intended to provide a network capable of transmitting power between generating sources and loads. The Transmission System is utilized by various generation sources and loads throughout the Eastern Interconnection via Network Integration Transmission Service or various other forms of Transmission Service. The implementation of the projects and operating solutions identified by application of this planning criteria shall result in a Transmission System for which the probability of initiating cascading failures is very low. The system should also provide operating flexibility including, but not limited to, allowing maintenance outages. Loss of load may be tolerated for some system outages which occur during maintenance shutdowns, double and extreme contingencies.

In meeting the above objectives, the planning engineer must recognize present state-of-the-art equipment, understand construction practices, scheduling and the practical needs of operating the electrical system. It must be recognized that thermal overloading can shorten equipment life and lead to sudden failures and that abnormal voltages can also cause equipment failures and/or voltage sensitive equipment to be adversely affected. The planning engineer also needs to be cognizant of intangible considerations, such as the social and political implications of his work which include visual and ecological effects. In particular, one social implication that the planning engineer needs to consider is the social benefit of the loads being able to access the most economical generation available. Many of these elements cannot be guided by exact rules and the engineer's judgment must be factored into the proposed projects. In summary, the material gathered in this manual is intended to provide basic system planning guidelines. The planning engineer, however, must still apply ingenuity, experience and judgment in order to develop projects which lead to an economic and reliable power system and supports the access to economical generation. Where judgment is used, it should be recognized as such and documented so as to be part of the record for future planning.

The introduction of wind generation in Michigan has added a new dimension to the study and planning of the transmission system. One of the goals of any transmission system study should be to develop a transmission system capable of reliably delivering all types of generation on the system to the required loads at all appropriate load levels. Wind generation typically is at its highest output when system loading is not at its peak. The ITCT and METC planning criteria shall apply to system conditions at all load levels (as detailed in Table 2), including those when wind generation is at its peak.

4 Thermal Loading and Voltage Planning Criteria

4.1 Description

The transmission system is used to transmit power and energy from interconnected generation plants to interconnected loads. Some of the generation and load that utilize the Transmission System are not directly interconnected with the Transmission System but are part of the larger interconnected grid and utilize the Transmission System through its ties with neighboring systems.

4.2 Design Considerations

The Transmission System should be designed such that foreseeable normal and contingency conditions do not result in equipment damage or in exceeding acceptable loss of load (see Table 2 – Transmission System Planning Standards for allowable load loss by contingency type). Planning studies are to be completed for projected annual peak system load conditions, but the planning criteria is also applicable for loads less than the annual peak system load level. Planning studies to evaluate projected shutdown conditions (a single non-generator element shutdown plus a single element forced out) however, are to be evaluated at a lower load level (see Table 2 – Transmission System Planning Standards).

The Transmission System will be planned to be within its thermal capacity, to remain stable, to be within equipment short circuit capabilities, and to be within acceptable voltage limits while meeting projected needs of users of the transmission system. These needs may be communicated by reservations on the transmission system including network service requests or through other mechanisms.

When evaluating the system's expected performance, in the absence of specific customer identified generation resources (such as designated network resources), generation shall be dispatched on an assumed economic and probabilistic basis. In any case, including the system "normal" case, reasonable assumed forced and scheduled generator outages shall be considered. Studies to determine transmission needs for a given power plant will be based on the maximum reasonable expected generation output from that plant and adverse, but credible, dispatch scenarios for other nearby generation shall be considered.

4.3 Project Proposal Guidelines

Project proposals will be submitted if one or more of the following guidelines are met.

- Replacement of equipment which is unsafe to operate and/or presents a hazard. This includes projects required to replace interrupting devices that could be subjected to fault currents which exceed momentary or interrupting ratings, as well as projects required to replace equipment that periodic maintenance tests have shown to have incipient failure.

- Replacement of equipment that presents a costly maintenance burden. This includes projects required to replace equipment that periodic maintenance tests have shown increasing economic costs to maintain for reasons such as that equipment that is, or is becoming, obsolete.

- Interconnection of reasonably documented new customers or committed increases in load at existing customer stations. Related projects should be proposed if one or more of the guidelines under criteria Sections 4 through 7 are violated.

- Relocation of Transmission System facilities on public property as required by federal, state, county or local governmental units. Other requests for relocations are to be done only if the requestor has contracted to pay for the relocation or if economic justification exists.

- Repair, rebuild or replacement of equipment which has failed.

- Requirements to maintain spare equipment to a level sufficient to provide timely replacements for normal failure rates.

- Mitigation of instances with violations or projected violations of the planning criteria.

- Purchase of corridor, station and/or substation sites as needed for other projects. Approved property purchases can also be associated with reasonable expected future needs.

Reasonable future conditions such as load growth, changes in regional and interregional system flow patterns and future generators much be considered when developing projects. The goal is to develop a robust transmission system today which can be efficiently expanded to reliably and economically accommodate tomorrow's load and generation patterns.

4.4 Voltage and Facility Loading Criteria

4.4.1 Generally Applicable Criteria

Table 2 – Transmission System Planning Standards

ITC *Transmission* Description	NERC Category	Allowable Load Loss[l]	BES Level[n]	Ratings Used	Load Level[k] (% System Peak)	Minimum Voltage[h,r]	Maximum Voltage[h,r]
System Normal[e]	A	none	EHV, HV	normal	100%	97%	107%[b]
Single Generator (no Generators in proximity off in base case)[f]	B1	none	EHV, HV	normal	100%	97%	107%[b]
Single Generator (with other generators in proximity off in base case)[f]	B1	none	EHV, HV	emergency[c]	100%	92%	107%[b]
Single UG Cable[f]	B2	none[a]	EHV, HV	emergency[c]	100%	92%	107%[b]
Single OH Line[f]	B2	none[a]	EHV, HV	emergency[c]	100%	92%	107%[b]
Single Transformer[f]	B3	none[a]	EHV, HV	emergency[c]	100%	92%	107%[b]
Shunt Device[f,o]	B4	none[a]	EHV,HV	emergency[c]	100%	92%	107%[b]
Opening of a line section w/o a fault[f,o]	B5	none[a]	EHV,HV	emergency[c]	100%	92%	107%[b]
Bus Section[f]	C1	none[a]	EHV	emergency[c]	100%	92%	107%[b]
		100 MW[i]	HV	emergency[c]	100%	92%	107%[b]
Circuit Breaker[f]	C2	none[a]	EHV	emergency[c]	100%	92%	107%[b]
		300 MW[i]	HV	emergency[c]	100%	92%	107%[b]
Shutdown + Contingency[f,m,q]	B1, B2 or B3[j]	none[a]	EHV, HV	emergency[c]	85%	92%	107%[b]
Double Circuit Tower (DCT)[f]	C5	300 MW[i]	EHV, HV	emergency[c]	100%	92%	107%[b]
Double Contingencies[d,f,m,q]		500 MW[i]					
1. After First Contingency (Prior to System Re-Adjustment)	C3	none[a]	EHV, HV	emergency[c]	100%	Variable[g]	107%[b]
2. After First Contingency (After System Re-Adjustment)	C3	none[a]	EHV, HV	normal	100%	Variable[g]	107%[b]
3. After Second Contingency (Prior to System Re-Adjustment)	C3	500 MW	EHV, HV	emergency[c]	100%	Variable[g]	107%[b]
Extreme Contingencies[d,f]	D	no cascading	EHV, HV	emergency[c]	100%	no cascading	no cascading

a) There may be some consequential load loss in the event of the loss of a radial circuit, a transformer in direct series with a radial circuit or the loss of a load fed from a radial tap off of a network circuit provided the load lost was served directly by the outaged facility.

b) 110% is the generally applicable system (physical) limit and represents SOLs. For some specific locations a more stringent SOL limit may be applied. System studies should monitor and plan to 105% voltage due to contractual obligations with the Load Serving Entities. The contractual obligation does not define the SOL.

c) The emergency rating applied shall be of an appropriate duration considering both the piece of equipment limited and the contingency studied.

d) The NERC Planning Standards consider a single category B event followed by operator intervention followed by another category B event as a category C event. The loss of two elements without time between for operator action is interpreted by ITC to be more severe than category C and is treated like an extreme contingency.

e) Normal Conditions include an appropriate set of scenarios that consider appropriate generators not in the dispatch

f) Emergency conditions include an appropriate set of scenarios that consider appropriate generators not in the dispatch in addition to the single, double and multiple transmission element outages. This would typically include at least a single generator dispatched off prior to applying the contingency under study.

g) Minimum voltage during a double contingency or an extreme contingency is determined by the minimum voltage required at power plants to avoid widespread cascading outages. The minimum voltage requirements vary from plant to plant.
h) Some buses have individual voltage limits. These are reviewed on a case by case basis.
i) The voltage limits listed are steady state voltage limits. Voltage control devices (tap changers, switched shunts, phase shifting transformers...) should be set to control during the analysis.
j) In no circumstance should the contingency result in automatic tripping of a circuit or safety violations.
k) The Load Level shown is the maximum load level to which this part of the criteria should be applied. It is also valid at any load level less than that shown, for instance when studying the impact of wind generation dispatched at a load level less than system peak.
l) Allowable load loss is the sum of 1) any load lost directly following the event such as load fed radially off an outaged line and 2) any load shed to get within applicable limits.
m) Appropriate classification for multiple outages involving generators shall depend on the status of other generators in proximity in the starting case. For example, the shutdown of a generator and subsequent contingency shall be considered a "shutdown + contingency" should generation already be off in the proximity in the normal case. If generation is not off in the proximity in the base case, this shall be considered as a simple contingency.
n) Bulk Electric System (BES) level references include extra-high voltage (EHV) facilities defined as greater than 300 kV and high voltage (HV) facilities defined as the 300 kV and lower voltage systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of firm transmission service and non-consequential load loss.
o) Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
p) Opening one end of a line section without a fault on a normally networked transmission circuit such that the line is possibly serving load radially from a single source point.
q) A protection system maintenance shutdown or failure would constitute a viable contingency for Category B3 or C3 events.
r) All Nuclear Plant Interface Requirements (NPIRs) applicable to generator plants in the ITCT and METC footprints shall be monitored and upheld.

The reactive reserve in an area (comprised of "unused" reactive capability of generators or shunt capacitors) should be monitored in studies to identify possible voltage collapse scenarios. Low reactive reserves may be an indication of being near the "knee" of the PV curve.

Post-contingency voltages including those for the NERC category C events should be high enough to ensure that there would be no motor stalling on the distribution system. Other related tests should be applied as appropriate to examine the system's susceptibility to voltage collapse.

When studying the system, generators shall be dispatched on a basis that considers committed resources, assumed economics, and probabilities of forced and scheduled generator outages. It may be appropriate to consider conditions with multiple generator units unavailable in an area especially if the conditions being studied may be prevalent for an extended period of time. Further, as appropriate, the system should be analyzed to consider vulnerability to the extended outage or the retirement of any particular generating unit or plant.

For any reasonably expected generation dispatch pattern, or a dispatch that represent an average condition, notwithstanding documented application of judgment to the contrary, projects should be proposed if the loading on system elements (overhead conductors, underground cables and/or station equipment), minimum voltages, maximum voltages, or the amount of load loss are outside of the applicable contingency category parameters as set forth in of Table 2 - Transmission System Planning Standards.

Allowable load loss includes any load lost with the contingency plus manual load shedding. The planning engineer should evaluate any location for reductions in load that would reasonably be expected to reduce loading on the limiting circuit.

4.4.2 Shutdown Conditions

For load levels below the maximum planned for load level with shutdowns (see Table 2 - Transmission System Planning Standards), it is expected that the shutdown[1] of a single component would result in element loadings and system voltage with normal ranges as the system will be planned to be able to withstand a pre-existing shutdown of an element at or below a pre-determined load level. Further, it is expected that contingent loss of a component on top of the shutdown of a single component would result in element loadings and system voltages within emergency ranges.

Current TPL standards specify system performance studies be conducted to include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned outages are performed. This applies to both single and multiple contingency types (NERC category B, C and D). Planned outages in this case include only those scheduled from at least one year out from the time the planning analysis is finalized. Since maintenance outages are not typically planned that far in advance, ITC Planning Criteria goes beyond the compliance requirements and includes all combinations of NERC category B (single) contingencies with all other NERC category B (single) contingencies. The intent of this criteria is to ensure sufficient transmission system is planned to allow the required maintenance of Bulk Electric System (BES) equipment while being able to withstand the relatively higher probability of a NERC category B (single) event. Due to the relatively lower probability of a NERC category C (multiple) or NERC category D (extreme) contingency event, only scheduled planned outages are combined with category C and D contingencies in planning analysis.

When studying shutdown conditions, generators shall be dispatched on a basis that considers committed resources, assumed economics, and probabilities of forced and scheduled generator outages. It is assumed that during shutdowns, Transmission System Operations will minimize the risk exposure of such outages. However, it may be appropriate to consider conditions with multiple generator units unavailable related to generator maintenance outages or long generator start up times.

There must be a significant, continuous time during the year when a system element can be shutdown for inspection, maintenance, adjacent hazard and/or element replacement. Planning studies must therefore evaluate the system under shutdown conditions using the maximum planned for load level with shutdowns (see Table 2 - Transmission System Planning Standards). The maximum planned for load level with shutdowns should periodically be re-evaluated to ensure that the application of that criterion is consistent with the requirement of having a significant, continuous time during the year when a system element can be shutdown for inspection, maintenance, and adjacent hazard and/or element replacement.

[1] A shutdown is defined as a planned or forced outage of any single element on the transmission system.

4.4.3 Single Contingency Followed by Operator Action Followed by Another Single Contingency

The forced outage of a single generator, transmission circuit (or portion thereof) or transformer followed by operator interaction and then followed by another forced outage of a single generator, transmission circuit (or portion thereof) or transformer is considered to be a NERC Category C event. Under these conditions, no more than a pre-determined amount of Transmission System annual system peak load can be projected to be lost. This load loss considers intentional load shedding and the forced outage of load subsequent to the contingency. For load levels below the maximum planned for load level with shutdowns, it is expected that no load would be lost under these type of conditions as the system will be planned to be able to withstand the shutdown of an element plus the contingency loss of another element (see Table 2 – Transmission Planning Standards).

4.4.5 NERC Category D – Extreme Event

The Transmission System will be evaluated using a number of extreme contingencies that are judged by Planning to be critical. It is not expected that it will be possible to evaluate all possible facility outages that fall into NERC Category D. These events may involve substantial load and generation loss in a widespread area. These critical category D contingencies should not result in cascading outages beyond the Transmission System area and any immediately adjacent areas.

5 Stability Criteria

Stability is the ability of a turbine-generator or power system to reach an acceptable steady-state operating point following a disturbance. This requires that thermal loadings, load loss, and voltage following the disturbance are within the guidelines established in Table 2 – Transmission Planning Standards.

Pre-disturbance generation conditions should be selected to maximize generator real power, and minimize generator reactive power and voltage in the area where the disturbance is to be simulated. Power plants must maintain transient and voltage stability and have no adverse impact on the rest of the system, including other connected generators, when operating anywhere in the range from 0.90 lagging to 0.93 leading power. Where the generator does not have the capability to achieve the entire power factor range described above, it must be maintain stability throughout the actual feasible power factor range at the minimum generator voltage. Turbine-generator and system stability shall be maintained during and after the most severe of the contingencies listed below:

1. With the transmission system normal, a three-phase fault at the most critical location[a] with normal[b] clearing.
2. Simultaneous phase-to-ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal[b] clearing.
3. A double phase-to-ground fault at the most critical location[a] with delayed[c] clearing.
4. With one element (transmission line, transformer, protective relay, or circuit breaker) initially out of service, a permanent three phase-to-ground fault at the most critical location[a].

5. A permanent phase-to-ground fault on a circuit breaker with normal clearing.

Generator minimum reactive limits should be determined based on the most severe post disturbance operating point that results from applying the above stability criteria. Generator minimum reactive limits are determined with and without the automatic voltage regulators in service.

a) Faults should be placed on generators, transmission circuits, transformers, and bus sections.
b) Normal clearing means that all protective equipment worked as intended and within design guidelines.
c) Delayed clearing means that a circuit breaker, relay or communication channel has malfunctioned or failed to operate within design guidelines. If the delayed clearing is due to a failure to operate, local and remote backup clearance is appraised.

6 Short Circuit Criteria

Short circuit currents are evaluated in accordance with industry standards as specified in the American National Standards report ANSI C37.5-1981 for older breakers rated on the total current (asymmetrical) basis and the American Standards Association report C37.010-1979 (Reaff 1988) for new breakers rated on a symmetrical current basis.

In general, fault currents must be within the specified momentary and/or interrupting ratings for the devices for studies made with all facilities in service, and with generators and synchronous motors represented by their appropriate (usually sub-transient saturated) reactance.

7 Power Quality/Reliability Criteria for Delivery Points

Details of Power Quality and Reliability Criteria for Delivery Points are covered in the individual Interconnection Agreement Documents with the Load Serving Entities. The Planning Engineer shall propose projects as required in those agreements.

8 Voltage Deviation Standards

8.1 Capacitor Switching

The maximum percent change in system voltage under normal system conditions shall be 3% when sizing capacitor banks. Banks will also be sized to avoid harmonic resonance.

8.2 Loss of Generation

Over the normal generation availability range, with all transmission elements in service, the voltage change measured anywhere in the system shall be considered for tripping a single generator.

8.3 Loss of a Transmission Element

Over the normal generation availability range, the voltage change measured anywhere in the system shall be considered for the loss of a single transmission element.

9 Coordination with Other Transmission Systems

9.1 Joint Planning

The Transmission System has interconnections with neighboring systems. These systems include neighboring transmission systems as well as distribution systems. ITC*Transmission* and Michigan Electric Transmission Company also participate in the regional reliability coordination group called Reliability*First*, and have therefore agreed to certain principles for system planning and operating established therein.

The contractual commitments with the interconnected neighbors, as well as the properties of interconnected operations require coordinated joint planning with others of not only the interconnection facilities, but also consideration of the networks contiguous to those interconnections.

9.2 Interchange Capability Criteria

Interconnections with other transmission systems are intended to facilitate the economic and reliability needs of generators and loads directly interconnected with the Transmission System. In addition, these interconnections can also support the economic and reliability needs of generators and loads not directly interconnected with the Transmission System. Interchange capability is the amount of power that can be transferred across transmission systems without exceeding the transmission system's facility limitations. Accordingly, the evaluation and planning of interchange capability is necessarily a joint effort by the concerned utilities.

The desired import capability based on the Transmission System's annual peak load is to be provided for network conditions as defined in NERC document "Transfer Capability, A Reference Document" for normal and first contingency single element outages. Single elements include any single generator, transmission circuit (or portion thereof) or transformer.

10 Special Protection Systems (SPS)

It is ITC*Transmission* and METC policy that new Special Protection Schemes (SPS) not be installed on the ITC*Transmission* and METC systems. ITC*Transmission* and METC will not support the installation of an SPS on a neighboring system whose purpose is to mitigate potential issues on the ITC*Transmission* or METC systems.

For those SPS's that have already been placed in service, periodic reviews should be performed to ensure that the scheme is deactivated when the conditions requiring its use no longer exist or system improvements to remove the SPS are warranted.